

A MODEL FOR ALASKA: DEREGULATION IN THE FAR NORTH

This Note considers whether Alaska should follow the recent state trend towards deregulation in the electrical market. It first examines the reasons behind the national trend towards deregulation. Next it describes Alaska's current electrical energy market and regulatory scheme, and how it differs from the rest of the states. The Note then considers the regulatory schemes recently passed by other states, focusing on California, Montana, and Oregon. It then contemplates what Alaska can learn from the other states and concludes that if Alaska decides to deregulate, it should do so cautiously, with due regard to Alaska's unique market conditions and the needs of residential customers.

I. INTRODUCTION

Electrical deregulation is a hot topic. Every state is currently implementing or studying some form of restructuring in the retail electrical market.¹ Proponents of deregulation claim it lowers rates and allows for innovation in a stagnant, regulated market.² Opponents claim that deregulation primarily benefits large, industrial customers, and that residential customers suffer in deregulated markets.³ Opponents argue that electricity is not like

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1. See *infra* note 87.

2. See Michael Even Stern & Margaret M. Mlynczak Stern, *A Critical Overview of the Economic and Environmental Consequences of the Deregulation of the U.S. Electric Power Industry*, 4 ENVTL. L. 79, 101-05 (1997) (concluding that deregulation can bring benefits, but that the overriding goal of the restructured industry will be profit maximization).

3. See Margaret Kriz, *Doubts About Electricity Deregulation*, NAT'L J., Mar. 6, 1999, at 621 (citing an Agriculture Department study indicating that the biggest losers in deregulation may be rural cooperatives with high construction costs, particularly if they lose access to low-cost preference power from federal power marketing authorities).

any other commodity; it is a necessity of life, requiring special protection from the vagaries of competitive markets.⁴

While each state that implements deregulation must consider its own unique situation, the state of Alaska stands alone in the electrical market. Alaska is not connected to the lower forty-eight states by a transmission grid, and many rural areas of the state have isolated transmission and generation facilities.⁵ A small customer base limits opportunities for developing competitive markets and economies of scale.⁶ Still, proponents of deregulation argue that even in Alaska, competition will spark innovation and reduce prices.⁷ They point to serious inefficiencies in the current market — particularly the excess energy that goes to waste because there is no market for it — to support their argument that Alaska residents can benefit from competition.⁸

The Alaska Legislature is currently exploring options for restructuring its retail electricity market and is considering implementing a pilot program.⁹ Alaska should learn from the legislative models presented by California, Montana, and Oregon. If Alaska adopts deregulation legislation based on the Montana model, it could easily find itself with monopoly conditions and market share problems because of the lack of adequate transmission facilities and limited number of suppliers.¹⁰ If it adopts the California plan, residential customers could see little benefit or higher rates in the long term, while industrial customers would enjoy lower prices.¹¹ Alaska's best alternative is to adopt a consumer-protective stance similar to that proposed in Oregon.

4. See George C. Loehr, *Ten Myths About Electric Deregulation*, 135 No. 8 PUB. UTIL. FORT. 28 (Apr. 15, 1998) (arguing that deregulation will compromise reliability).

5. See *infra* notes 55-57 and accompanying text.

6. See Karl R. Rabago et al., *Final Report: Study of Electric Utility Restructuring in Alaska* (Apr. 1999) (last modified Jun. 1, 1999) <http://www.state.ak.us/rca/r97010/CH2_Final_Report.htm> [hereinafter CH2M Study].

7. See *id.* at 2.3.

8. See *id.*

9. See Karl R. Rabago & Tom Feiler, *Recommendations to the Alaska State Legislature and the Alaska Public Utilities Commission Regarding a Retail Pilot Program* (Mar. 1, 1999) (last modified Oct. 4, 1999) <<http://www.state.ak.us/rca/Electric.htm/>> (recommending that Alaska implement technological and regulatory reforms to prepare for the transition to competition, implement a power pool or independent system operator (“ISO”), and develop a pilot program according to goals for a deregulated environment).

10. See *infra* notes 106-113 and accompanying text.

11. See *infra* notes 93-105 and accompanying text.

However, even a plan like Oregon's should be adopted in stages in order to prepare the market for competition. Deregulation could benefit Alaska, but regulators must proceed cautiously, with due regard to Alaska's unique market conditions and the needs of residential customers.

II. DEREGULATION: SETTING THE SCENE

A. Forces Converge on Electric Utilities

Traditionally, electric utilities have been vertically integrated companies¹² with fully regulated rates.¹³ This tradition was built, at least in part, on the assumption that the electrical market is a natural monopoly.¹⁴ In the 1970's, however, the traditional view of

12. The primary components of the electric energy market are generation, transmission, and distribution. Transmission facilities take electricity at a high voltage and send it to a load center, where it is converted to a lower voltage and distributed to retail customers. See LEONARD S. HYMAN, *AMERICA'S ELECTRIC UTILITIES: PAST, PRESENT AND FUTURE* 19 (5th ed. 1994). A vertically integrated utility contains all three components and creates one rate that includes the costs and expenses for each component. It is not altogether clear why utilities developed this way. Although the conventional wisdom centers around economies of scale in generation and service of customers, other factors, like the willingness of the utility companies to receive a lower rate of return than isolated suppliers, might have been just as important. See *id.* at 90-91.

13. The Federal Energy Regulatory Commission regulates the sale of wholesale electrical energy and interstate transmission of electricity under the Federal Power Act. See Federal Power Act § 205, 16 U.S.C. § 824(a) (1994). State public utility commissions regulate retail distribution and sale of electricity by private, investor-owned utilities in every state but Nebraska. See PETER FOX-PENNER, *ELECTRIC UTILITY RESTRUCTURING: A GUIDE TO THE COMPETITIVE ERA* 98 (1997). Municipal utilities and public utility districts operate a little differently. In 13 states, public utility commissions regulate these government-owned bodies, which generally do not own transmission or generation facilities. See *id.* at 103. Elsewhere, they set their own rates. The regulation of member-owned cooperatives, or co-ops, also varies from state to state. See PUBLIC UTILITIES REPORTS, *ELECTRIC COOPERATIVES: ON THE THRESHOLD OF A NEW ERA* 113-15 (1996). In 25 of 46 states, state public utility commissions do not regulate co-ops' rates. In 9 states, state commissions have no jurisdiction over co-ops. See *id.* at 113. Each state's public utility commission determines rates differently, but they are bound by due process to ensure that utilities are able to recover reasonable costs and earn a fair return. See generally Walter Pond, *The Law Governing the Fixing of Public Utility Rates: A Response to Recent Judicial and Academic Misconceptions*, 41 ADMIN. L. REV. 1, 5-13 (1989).

14. See CHARLES F. PHILLIPS, JR., *THE REGULATION OF PUBLIC UTILITIES: THEORY & PRACTICE* 4-9 (3d ed. 1993); see also HYMAN, *supra* note 12, at 4, 176-

utilities began to change. Customers, policy-makers, and politicians speculated over the potential for competition to benefit the electric energy market. A combination of forces made this shift in thinking possible. First, forecasts of increased demand and a threat of high prices for oil encouraged utilities to invest significant amounts of money into developing new forms of electrical generation, particularly nuclear power plants.¹⁵ A period of inflation and high interest rates increased the cost of this capital development, forced utilities to raise rates, and left customers questioning the high prices and rate increases.¹⁶ As the cost of nuclear development rose, so did concern over the environmental impacts of these plants.¹⁷ Eventually, problems like the meltdown at Three Mile Island called national attention to the danger of nuclear power production.¹⁸

After investing large amounts of money into new generation, utilities were dismayed to find that the forecasted demand did not materialize.¹⁹ Instead, vertically integrated utilities had excess capacity and enormous costs. To make matters worse, inflation increased the costs of operation for the nuclear plants while gas

77 (describing the various bases for the concept, including utilities' provision of a capital intensive, non-storable service, and the possibility that service would be impaired by competitive pricing). Some argue that utilities are no longer a natural monopoly (if they ever were) because economies of scale no longer exist, and a decentralized market for generation has developed. See HYMAN, *supra* note 12, at 180.

15. See Promoting Wholesale Competition Through Open Access, Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed. Reg. 21,540, 21,543 (1996) [hereinafter Order 888]; see also HYMAN, *supra* note 12, at 14 (associating rising costs and investment in nuclear power with the environmental movement). The Organization of the Petroleum Exporting Countries, or OPEC, oil embargo furthered the fear of future oil prices. See Jeffrey D. Watkiss & Douglas W. Smith, *The Energy Policy Act of 1992 — A Watershed for Competition in the Wholesale Power Market*, 10 YALE J. ON REG. 447, 452 (1993). A further impetus for building new generation was that prior to the 1970's, costs for electric energy consistently declined as the size of power plants increased. See FOX-PENNER, *supra* note 13, at 89. Technological changes in the 1970's brought an end to these ever-increasing economies of scale, diminishing or even reversing the correlation between economy and size. See *id.* at 89-91.

16. See PHILLIPS, *supra* note 14, at 12.

17. See HYMAN, *supra* note 12, at 42-44.

18. See *id.* at 143.

19. See Order 888, *supra* note 15, at 21,543. Between 1970 and 1985, average residential electricity prices tripled. See *id.* at 21,544.

prices stayed low.²⁰ New technology in generation, particularly gas-fired turbines, allowed independent suppliers to produce lower cost power than integrated utilities.²¹ Finally, a growing environmental movement questioned the industry's investment decisions, and called attention to the potential for cost-efficient renewable resources.²² As all of these forces came together in the early 1980's, public utility commissions grew impatient with utilities, and started to limit or deny utilities the chance to recover their investments.²³ Policy makers began looking for ways to encourage innovation in a seemingly stagnant and flawed monopoly market.

B. Federal Intervention

The government's first answer to the call for innovation was the Public Utility Regulatory Policy Act of 1978 ("PURPA").²⁴ PURPA created a new type of power producer called a qualifying facility.²⁵ A power producer could become a qualifying facility if it met Federal Energy Regulatory Commission ("FERC")

20. *See id.* at 21,543.

21. *See id.* at 21,544.

22. *See* HYMAN, *supra* note 12, at 37-49.

23. Oregon provides an interesting example of this dynamic. In 1978, Oregon citizens passed an initiative prohibiting recovery by a utility of costs associated with "any construction, building, installation or real or personal property not presently used for providing utility service to the customer." OR. REV. STAT. § 757.355 (1998). It appeared that this ordinance would preclude recovery of costs from decommissioned nuclear power plants. However, in 1993, the Oregon Public Utility Commission ruled that the ordinance applied only to those plants that were never in service. *See* Portland General Electric Company, Order No. 913-117, 145 PUR 4th 113, 119 (Or. Pub. Util. Comm'n. 1993). This ruling allowed Portland General Electric to recover costs associated with the Trojan Nuclear Power Plant, which began operation in 1975 and was permanently closed in 1993. *See id.* at 115. After numerous appeals, the Public Utility Commission's decision was overturned. *See* Citizens' Util. Bd. v. Public Util. Comm'n, 962 P.2d 744, 746 (Or. Ct. App. 1998) ("We do not think that the word 'presently' . . . can plausibly be read as pertaining only to utility property that is not yet in use, and we conclude that the limitations of the statute apply to property that has ceased being used."). The legislature immediately responded with a bill to override § 757.355 and allow for recovery of property "retired from service." H.B. 3220, 70th Assembly, Reg. Sess. (Or. 1999). Although the bill was overwhelmingly approved by the legislature, consumer groups are now seeking to overturn it by a public referendum on the November 2000 ballot. *See* Jeff Mapes, *Consumer Groups Seek Vote on Payments for Trojan Plant*, OREGONIAN, July 16, 1999, at E6.

24. *See* Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117 [hereinafter PURPA].

25. *See* PURPA § 210 (codified at 16 U.S.C. § 824a-3(a) (1994)).

regulations as a small power producer or cogenerator.²⁶ PURPA forced utilities to buy power from qualifying facilities at “avoided cost” — the cost each utility would have paid if it had produced the energy itself or obtained it from an alternate source.²⁷ With PURPA, the government hoped to bring innovation to the industry through regulated competition, and to encourage the development of new suppliers. PURPA brought a number of new players into the electric industry — independent power producers and marketers — and forced many to question the assumption that the industry remained a natural monopoly.²⁸ After PURPA, FERC authorized new power producers and power marketers to sell wholesale energy at market-based rates on a case-by-case basis if the power producer could demonstrate that it did not have market dominance.²⁹ However, the inability of independent power producers to access transmission systems owned by monopolistic utilities limited their ability to compete in the wholesale market.³⁰ Investor-owned utilities (“IOUs”) continued to generate the majority of the power they sold, although they began to purchase some wholesale power from qualifying facilities and other independent power producers.³¹

In 1992, the Energy Policy Act³² attempted to address the difficulty faced by the independent power producers by giving

26. *See id.*

27. *See id.* (codified at 16 U.S.C. § 824a-3(b) (1994)). The term “avoided cost” is not in the statute, which refers to the “incremental cost to the utility of alternative electric energy.” *Id.* (codified at 16 U.S.C. § 824a-3(c)). As interpreted by FERC, avoided cost pricing should “encourage efficiency and innovation,” by providing for the growth of qualifying facilities, and should have no adverse impact on utilities because the price for energy from a qualifying facility is no more than what the utility would have to pay to generate the electricity itself. *See* Watkiss & Smith, *supra* note 15, at 453 n.23.

28. *See* Order 888, *supra* note 15, at 21,545.

29. *See id.* at 21,544.

30. *See id.* at 21,546; *see also* Watkiss & Smith, *supra* note 15, at 454-55 (providing examples of denials by utilities of transmission access for anti-competitive reasons). PURPA gave FERC the authority to order wheeling, but that authority was limited to situations in which the order would “reasonably preserve existing competitive relationships.” PURPA § 203 (codified at 16 U.S.C. § 824j(c)(1) (repealed 1992)); *see also infra* note 33. Clearly, this provision was antithetical to the use of wheeling authority to encourage competition.

31. In 1995, IOUs owned 68.8% of generation capacity for the United States, and produced an average of 75% of the power they sold. *See* FOX-PENNER, *supra* note 13, at 119-20 tbl.5.1. On the other hand, public utilities produce only about 17% of the electricity they sell. *See id.*

32. Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776.

FERC the authority to order wholesale wheeling³³ of power for any utility, power marketing agency, or any other person generating electricity for sale or for resale.³⁴ The Energy Policy Act also furthered the trend toward deregulation of electricity generation by designating a new category of power producers called exempt wholesale generators.³⁵ These exempt wholesale generators were excluded from the definition of electric utility companies,³⁶ and consequently were exempt from regulation under the Public Utility Holding Company Act.³⁷

C. FERC Takes Matters Into Its Own Hands

Although the Energy Policy Act gave FERC the authority to order wholesale wheeling, independent power producers did not rush to FERC to make wheeling requests.³⁸ Seeking out wholesale wheeling on a case-by-case basis actually gave the transmission

33. Wheeling is simply the practice of sending electricity through transmission lines for another party. Without access to transmission lines, an independent power producer has no means of transmitting electricity to its customers. Since they do not own transmission facilities themselves, independent power producers must rely on a utility to provide transmission. Utilities naturally have an interest in not opening their transmission facilities to their competitors. A wheeling order forces the utility that owns the transmission lines to send the independent power producer's energy to the independent's customers.

34. See Energy Policy Act of 1992 § 721(1) (codified at 16 U.S.C. § 824j (1994)) (stating that “[a]ny electric utility, federal power marketing agency, or any other person generating electric energy for sale for resale [sic] may apply to the Commission for an order under this subsection requiring a transmitting utility to provide transmission services (including any enlargement of transmission capacity necessary to provide such services) to the applicant”).

35. See Energy Policy Act of 1992 § 711 (codified at 15 U.S.C. § 79z-5a (1994)).

36. See *id.* (codified at 15 U.S.C. § 79z-5a(e)).

37. See Public Utility Holding Company Act of 1935 (“PUHCA”), Pub. L. No. 105-220, 49 Stat. 838 (codified at 15 U.S.C. § 79 (1994)). PUHCA led to the downfall of the large interstate holding companies that developed in the 1920's and 1930's. PUHCA prohibits the formation of any holding company twice removed from its operating subsidiary, and requires approval from the Securities and Exchange Commission for the purchase or sale of securities. See Amy Abel & Larry Parker, *Electricity: The Road to Restructuring*, CONG. RES. SERV., June 20, 1996, at 3-4 (Issue Brief) (on file with author). Exemption from PUHCA allows exempt wholesale generators to own interests in qualifying facilities and accumulate interstate holdings. See Watkiss & Smith, *supra* note 15, at 467.

38. At the time FERC issued Order 888, it had issued orders requiring wheeling in 12 cases. See Order 888, *supra* note 15, at 21,547; see, e.g., *City of Bedford*, 68 F.E.R.C. ¶ 61,003 (1994), *reh'g denied*, 73 F.E.R.C. ¶ 61,322 (1995); *Florida Mun. Power Agency v. Florida Power & Light Co.*, 67 F.E.R.C. ¶ 61,167 (1994), *order on reh'g*, 74 F.E.R.C. ¶ 61,006 (1996).

utility an even greater advantage over the power producer simply through the time delay caused by filing the request.³⁹ In Order 888, FERC attempted to remedy this situation by ordering all transmission lines to be operated on a non-discriminatory, open-access basis.⁴⁰ Order 888 required utilities owning transmission to provide open-access tariffs for their transmission services, and required the utility owning the transmission to take service for itself at the same tariff rates it charged other customers.⁴¹ To eliminate problems of cost-shifting, FERC required utilities owning transmission and generation facilities to functionally unbundle those services.⁴² That is, utilities had to separate the costs and rates for each component service so they would not be able to recover costs from generation or retail distribution by setting higher rates for transmission.

Although FERC did not order divestiture of generation or transmission assets, it did provide principles for evaluating proposals for an Independent System Operator (“ISO”),⁴³ and

39. See Order 888, *supra* note 15, at 21,547.

40. See *id.* at 21,550. As an agency rule, Order 888 could not expand FERC’s legislative authority. Instead, FERC interpreted its existing authority under the Federal Power Act (“FPA”) as authorizing the imposition of mandatory wheeling and open access tariff rates for transmission. See *id.* at 21,560-63. Section 206 of the FPA authorizes FERC to “remedy undue discrimination.” FERC held that case-by-case wheeling orders under § 211 of the FPA actually furthered discrimination, because of the time delays and the inherent inequalities in the system. Thus, FERC concluded that it has authority under § 206 to remedy the discriminatory situation perpetuated by § 211. See Order 888, *supra* note 15, at 21,562-63.

41. See Order 888, *supra* note 15, at 21,552. FERC does allow utilities to favor their own transmission needs when determining capacity. Order 888 permits utilities to reserve transmission service to serve native load growth. See *id.* at 21,574. However, FERC retains the authority to order the expansion of transmission capacity.

42. See *id.* at 21,552. Order 888 also requires all public utility transmission suppliers to maintain a “code of conduct” that defines acceptable practices for the interaction of generation and transmission employees and marketing functions. See *id.* FERC views this code of conduct as necessary to protect independent generators and power marketers from discrimination and unfair market practices in the absence of actual divestiture of generation assets by public utilities. See *id.*

43. See *id.* at 21,595-97. FERC lists eleven principles for assessing ISO proposals: (1) the ISO’s management structure must be fair and non-discriminatory; (2) the ISO and its employees should not have financial interest in the ISO or market participants; (3) the ISO must provide open-access tariffs and ensure non-discriminatory access to transmission; (4) the ISO must maintain short-term reliability of the transmission grid; (5) the ISO should control the grid within its region; (6) the ISO must identify and relieve transmission restraints and

noted that it would be open to other mechanisms for ensuring non-discriminatory access to transmission.⁴⁴ An ISO is an independent, typically non-profit entity that is not financially associated with a utility. Utilities relinquish control over the operation of their transmission lines to the ISO, but retain the transmission assets. In theory, the ISO's independence ensures that it manages transmission lines fairly and without discrimination. Some power producers argue that in the absence of an ISO or similar entity,⁴⁵ functional unbundling cannot eliminate discrimination in transmission, because technical separation of functions does not eliminate the utility's overall profit-seeking motive, and transmission-owning utilities can manipulate access to their facilities to favor their own generators.⁴⁶

In the realm of market-based pricing, Order 888 provided a tiered structure. In *Kansas City Power & Light Company*,⁴⁷ FERC approved market-based rates for new generation despite the absence of a showing that the generator lacked market power. Order 888 codified *Kansas City Power & Light*, creating a rebuttable presumption that there is no market dominance by new

have some control over generation facilities; (7) the ISO must have incentives to operate efficiently; (8) the ISO should promote efficient use of and investment in all aspects of electrical energy sales; (9) the ISO must make information publicly available via the Internet; (10) the ISO should coordinate with neighboring regions; and (11) the ISO should establish an alternative dispute resolution process. *See id.*

44. *See id.* at 21,552.

45. Independent power producers and marketers also support the formation of an independent for-profit transmission corporation, or transco. *See generally* Stephen Angle & George Cannon, Jr., *Independent Transmission Companies: The For-Profit Alternative in Competitive Electric Markets*, 19 ENERGY L.J. 229 (1998). Mary Hain, Director of Federal Regulatory Affairs with Enron Corporation, argues that a transco would be more effective than an ISO because the transco would have rate incentives to build new transmission, maximize system usage, and eliminate so-called "pancake rates" where each ISO piles on a different access charge. She also argues that a transco can maintain operation control, manage reliability and plan expansion better than an ISO. *See* Mary C. Hain, Federal Energy Regulatory Commission and Energy Law, Mar. 2, 1999 (unpublished presentation on file with the author).

46. *See generally* Petition for a Rulemaking on Electric Power Industry Structure and Commercial Practices and Motion to Clarify or Reconsider Certain Open-Access Commercial Practices; Nos. RM 95-8-000 & RM 98-5-000 (Mar. 25, 1998). *See also* Hain, *supra* note 45.

47. 67 F.E.R.C. ¶ 61,183 (1994) (concluding that improvements in market entry for wholesale generators obviates the need for demonstration of a lack of market dominance for new generation).

generators.⁴⁸ For the existing generation, Order 888 held that FERC must consider evidence of market dominance on a case-by-case basis before accepting market-based rates.⁴⁹ Utilities with transmission capacity were also required to file open access transmission tariffs to demonstrate the absence of transmission market power.⁵⁰

Significantly, Order 888 provided for the recovery of stranded costs, a key provision for many utilities.⁵¹ A stranded cost is a “legitimate, prudent and verifiable cost” that a public utility incurs with regard to a wholesale or retail customer.⁵² Utilities accumulate stranded costs because prior to Order 888 planning decisions were premised upon a stable customer base. After Order 888, that stable customer base no longer exists. A customer that used to buy wholesale power from a utility might only require transmission services from that utility once it is able to buy electrical energy from another wholesale generator. Similarly, after Order 888, a retail customer of a utility might require transmission and generation services only if it is able to contract with an independent power producer.

Finally, FERC mandated the creation of an Open Access Same-time Information System (“OASIS”), an Internet information pool where utilities post information about their transmission system and pricing.⁵³ OASIS prevents utilities from hoarding information about their transmission services, creating “sweetheart” deals for certain utilities or power producers by concealing accurate pricing information or not revealing the extent of the utility’s capacity to handle additional load.

In Order 888, FERC opened interstate transmission lines to wholesale access, but lacked jurisdiction to order open access to

48. See Order 888, *supra* note 15, at 21,553. An intervenor could rebut this presumption with evidence that a new generator would be able to exert market power based on factors like its proximity to existing transmission. See *id.* FERC also maintained its authority “to consider whether there is evidence of affiliate abuse or reciprocal dealing,” providing intervenors with another avenue to challenge the presumption of no unfair market power. See *id.*

49. See *id.* at 21,555.

50. See *id.* at 21,553.

51. See *id.* at 21,629-30.

52. Order 888 places limits on the ability of a utility to recover costs for new contracts that do not include an explicit provision for the recovery of stranded costs. See *id.* at 21,638.

53. See generally Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct, 61 Fed. Reg. 21,737 (1996).

retail distribution facilities. Many expected states to complete the deregulation process by ordering retail wheeling, but this has not occurred. Although many states have instituted some sort of pilot program or actual deregulation legislation, many more are studying the issues and waiting to see what happens in other states.⁵⁴

III. ALASKA TODAY

Alaska's current electrical energy market and regulatory scheme differ greatly from most of the states in the contiguous United States. These differences present particular challenges to proponents of deregulation.

A. The Electrical Market in Alaska

The electrical grid in Alaska is as diverse and isolated as the state's population. The entire state contains only about 250,000 customers for utilities.⁵⁵ Many small generators that are not connected to any state-wide grid operate independently to provide service to individual villages.⁵⁶ These isolated villages pay up to five times as much for their electricity as residents of urban Alaska.⁵⁷ The only section of Alaska connected by a transmission grid is the "Railbelt" area, which runs from Fairbanks in the north to Valdez in the southeast and Homer in the southwest, and produces approximately 86% of the electricity generated in Alaska.⁵⁸ The Alaska Energy Authority owns the Intertie, which is an interconnection permitting passage of current between two or

54. Twenty-one states currently have some sort of restructuring legislation in place. See *infra* note 87. Several bills have been presented in Congress to require states to adopt direct access principles. See *How Federal Bills Address Electric Utility Restructuring Issues* (May 1998) (visited Oct. 22, 1999) <<http://www.naruc.org/Congressional/restructuringmatrix.htm>> (providing an overview of nine federal restructuring bills and draft proposals).

55. See Dan Joling, *Utility Redesign Gets Look*, ANCHORAGE DAILY NEWS, Jan. 19, 1999, at F1.

56. See generally *Alaska, Energy Information Administration, Status of State Electric Utility Deregulation Activity* (last modified Oct. 1, 1999) <http://www.eia.doe.gov/cneaf/electricity/st_profiles/alaska/ak.html> [hereinafter EIA-Alaska].

57. See Dan Joling, *Electric Plan Aids Villages; Urban Areas Would Boost Bush Utilities*, ANCHORAGE DAILY NEWS, Feb. 15, 1999, at D1.

58. See Black & Veatch, *Power Pooling/Central Dispatch Planning Study 2-1, U-97-140, Alaska Public Utility Commission* (Oct. 1998) (visited Oct. 22, 1999) <<http://www.state.ak.us/apuc/u97140/>> [hereinafter Black & Veatch Study]. Non-Railbelt utilities accounted for 23% of sales of electricity and 33% of revenues in Alaska in 1997. See CH2M Study, *supra* note 6, at 3.28-3.29.

more electric utility systems. The Alaskan Intertie currently connects the northern and southern Railbelt utilities.⁵⁹ A new Northern Intertie, connecting Fairbanks and Healy, is due to be completed in late 1999.⁶⁰ A Southern Intertie has been proposed to run from the Kenai area to Anchorage.⁶¹

Generation, transmission, and distribution in the Railbelt are provided by Alaska Electric Generation and Transmission, a cooperative formed by Homer Electric Association and Matanuska Electric Association; Anchorage, Municipal Light & Power ("ML&P"); Chugach Electric Association ("Chugach"); and Golden Valley Electric Association ("Golden Valley").⁶² The Seward Electric System also operates in the Railbelt, but does not own any generation facilities. All of these utilities own a partial share in Bradley Lake, a hydroelectric plant owned by the Alaska Energy Authority.⁶³ The Railbelt utilities participate in a loose power pool.⁶⁴ A recent study of transmission management found that both an ISO and a tight power pool would provide some cost benefits to the area.⁶⁵ However, the expenses involved in starting up such entities outweigh those benefits for the first ten years of operation.⁶⁶

Investor-owned utilities do not predominate in Alaska. In 1996, IOUs accounted for only 8.4% of retail sales, while co-ops accounted for 60.7%.⁶⁷ Golden Valley and Chugach are both co-

59. See Black & Veatch Study, *supra* note 58, at 2-5.

60. See *id.* at 5-15.

61. See *id.*

62. See *id.* at 2-1 to 2-5. Golden Valley recently purchased Fairbanks Municipal Utility System, giving it control over the northern section of the Railbelt. See *Golden Valley Annual Report* (visited Oct. 22, 1999) <<http://www.gvea.com/about/annrep.htm>>.

63. See Black & Veatch Study, *supra* note 58, at 2-5 tbl.2-1.

64. See *id.* at 2-6. The power pool that currently exists in the Railbelt consists of loose, bilateral agreements between and among generators and distribution utilities. See *id.* Under this system, utilities maintain control over their distribution and transmission systems, but are able to save money by contractually aggregating individual loads to better utilize both generation and transmission resources. See *id.* at 7-2. In a "tight power pool," as described in the Black and Veatch Study, utilities pool all generated power, with distribution controlled by an independent system operator or a representative of one of the members of the system. See *id.* at 6-5.

65. See *id.* at 6-7. A tight power pool could provide approximately 2-4% savings over the current loose power pool. See *id.*

66. See *id.*

67. See CH2M study, *supra* note 6, at 1.14 tbl.1-10.

ops.⁶⁸ Alaska Electric Light and Power, which operates around the state capital of Juneau, is the only IOU among the five biggest utilities in the state.⁶⁹ At one time, a federal power administration, the Alaska Power Administration, operated two hydroelectric plants in Alaska, but in 1995 the Congress terminated the Alaska Power Administration and sold its assets.⁷⁰

Alaska has no nuclear generation, and its few coal-fired plants account for only 4.6% of generation, in stark contrast to the national average of 71.9%.⁷¹ Alaska's reliance on gas and hydroelectric sources of generation accounts for it having some of the lowest emissions of sulfur dioxide, nitrogen oxide, and carbon dioxide in the nation.⁷²

B. The Current Regulatory Scheme

Like most states, Alaska has a public utility commission, the newly named Regulatory Commission of Alaska ("RCA"), which oversees rates, facilities, practices, and services offered by utilities.⁷³ Every public utility, including municipalities and co-ops,⁷⁴ must file a tariff with the RCA designating its rates, rules, and regulations.⁷⁵ However, if annual gross revenues of the utility amount to less than \$50,000, the utility is automatically exempted from regulation, and if revenues amount to \$500,000 or less, customers of the utility can petition to have the utility deregulated.⁷⁶ In either case, an election of at least 15% of eligible members or subscribers determines if the utility should be deregulated.⁷⁷ The regulated utility must set rates

68. See EIA-Alaska, *supra* note 56.

69. See *id.*

70. See Lori A. Burkhart, et al., 136 PUB. UTIL. FORT. 14, 17 (Oct. 15, 1998). The Alaska Power Administration was terminated by an act of Congress in 1995, and the first sale of the assets was completed on August 18, 1998. See *id.*

71. See CH2M study, *supra* note 6, at 1.09 tbl.1.6.

72. See EIA-Alaska, *supra* note 56.

73. See ALASKA STAT. § 42.05.141 (LEXIS 1998). The Alaska Public Utility Commission ("APUC") was dissolved in July 1999, and replaced with a newly named Regulatory Commission of Alaska, which assumed its responsibilities. However, the relevant statutes still refer to the APUC. See *id.*

74. Public utilities are defined as "every corporation whether public, cooperative, or otherwise, company, individual, or association of individuals . . . that owns, operates, manages, or controls any plant, pipeline, or system for (A) furnishing, by generation, transmission, or distribution, electrical service to the public for compensation . . ." *Id.* § 42.05.990(4).

75. See *id.* § 42.05.361(a).

76. See *id.* §§ 42.05.711(e)(f), 42.05.712.

77. See *id.* § 42.05.712(b). In 1989, three utilities (I-N-N Electric Cooperative, Levelock Electric Cooperative, and Coffman Cove Utilities Association) voted in

that are “just and reasonable.”⁷⁸ If the RCA determines that rates are unduly discriminatory, unjust or unreasonable, it determines new rates for the utility.⁷⁹ A public utility may not operate until it has received a certificate of public necessity.⁸⁰ If two or more public utilities offer identical services and the competition between them is “not in the public interest,”⁸¹ the RCA shall act to eliminate the competition.⁸²

Since 1993, electrical costs of rural Alaska have been subsidized by the Power Cost Equalization Fund.⁸³ The RCA certifies an applicant utility for participation in the program, and determines the extent of support that the participating utility’s customers will receive.⁸⁴ This Fund has been drained from its original endowment of \$67 million to a current balance of \$3 million.⁸⁵ The future of the program looks bleak. Legislators have proposed instituting a universal system charge to electric customers to continue the subsidies.⁸⁶

IV. STATE DEREGULATION: FROM CALIFORNIA TO OREGON

A. General Overview of State Deregulation

Twenty-one states have adopted legislation that restructures the sale of electric energy and allows retail customers to have direct access to energy service providers.⁸⁷ The variations in the

favor of being deregulated, while the Kodiak Electric Association members voted against the utility being deregulated. *See Utility Deregulation Election Results* (visited Oct. 4, 1999)

<http://www.state.ak.us/apuc/annualreports/98annl_rpt/V2P34.htm>.

78. ALASKA STAT. § 42.05.381 (LEXIS 1998).

79. *See id.* § 42.05.431(a). The RCU must make a simplified rate filing procedure available to co-ops. *See id.* § 42.05.381(e).

80. *See id.* § 42.05.221(a).

81. *Id.* § 42.05.221(d).

82. *See id.*

83. *See Joling, supra* note 57, at D1.

84. *See About the RCA* (last modified Aug., 3, 1999) <<http://www.state.ak.us/rca/about.htm>>.

85. *See Joling, supra* note 57, at D1.

86. *See id.*

87. As of October 1, 1999, the following states had enacted some form of restructuring legislation: Arizona, Arkansas, California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Montana, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, and Virginia. *See Status of State Electric Utility Deregulation Activity as of*

legislation from state to state are primarily a matter of degree. Deregulation plans generally recognize the right of utilities to recover stranded costs,⁸⁸ but differ on the length of time over which those costs are recovered, or the degree of discretion the public utility commission has to limit or deny recovery.⁸⁹ Most legislation provides for a universal system charge to fund public service functions such as the development of renewable resources or subsidization of power for low-income residents.⁹⁰ To protect consumers and ensure a measure of reliability, deregulated states typically create a certification process for suppliers before allowing them to enter the competitive market.⁹¹ Finally, state deregulation plans typically include a default service provider for those customers who do not choose a supplier on their own.⁹²

Oct. 1, 1999 (last modified Oct. 1, 1999) <http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html>.

88. For a definition of stranded costs, *see supra* note 52 and accompanying text. The bulk of deregulation stranded costs result from the avoided cost contracts with qualifying facilities, which were imposed by PURPA. These contracts, estimated on a long-term basis, proved in many cases to be wildly overestimated. *See FOX-PENNER, supra* note 13, at 138. One New York utility estimates that its qualifying facility contracts are approximately \$3.3 billion above market rates. *See id.*

89. California, for example, limits the recovery period to four years. *See CAL. PUB. UTIL. CODE* § 367 (West Supp. 1999). Rhode Island spreads recovery of stranded costs over 12 years. *See R.I. GEN. LAWS* § 39-1-27.4 (1997). The Oregon plan does not limit recovery to a specified term of years, and leaves the Public Utility Commission with the discretion to limit recovery of costs where recovery is not “in the public interest.” S.B. 1149 § 8(2), 70th Assembly, Reg. Sess. (Or. 1999); *see also infra* notes 114-131 and accompanying text.

90. In Montana, the Universal System Benefits Program “ensure[s] continued funding of and new expenditures for energy conservation, renewable resource projects and applications, and low-income energy assistance.” MONT. CODE ANN. § 69-8-402(1) (1999). Utilities contribute 2.4% of their annual retail sales revenue to the fund. *See id.* § 69-8-402(2). Maine, on the other hand, requires each competitive energy provider to produce 30% of its supply from renewable resources. *See ME. REV. STAT. ANN.* 35A § 3210 (3) (West 1998).

91. *See, e.g.,* 66 PA. CONS. STAT § 2809 (1999).

92. Massachusetts offers a default rate and a standard offer rate, along with direct access. *See MASS. GEN. LAWS* ch. 164, § 1B (Supp. 1999). The standard rate provides customers with a 10% rate reduction, but is available only until 2004. *See id.* The default rate is regulated by the Massachusetts Department of Telecommunications and Energy, and may not exceed the average market price for electricity in New England. *See id.* In Rhode Island, utilities must provide a standard offer until the year 2009 for customers who have not chosen an alternate supplier. *See R.I. GEN. LAWS* § 39-1-27.3 (1997). The utility is also the “provider of last resort” for customers who are not eligible for the standard rate. *See id.*

B. California Residential Customers Ask, “What About Us?”

1. *Deregulation in California.* Retail customers in California got their first taste of direct access in March 1998.⁹³ Deregulation seemed a natural fit for California, which had the tenth most expensive electricity in the country, and the largest non-utility generation capacity in 1996.⁹⁴ The California deregulation legislation has some standard provisions, as well as some unique ones. Utilities can recover stranded costs, but they are placed on an aggressive recovery schedule that caps costs after the year 2001,⁹⁵ and limits recovery for certain costs of coal-fired plants.⁹⁶ Small commercial and residential customers received an immediate rate reduction of ten percent, and they must continue to receive this ten percent reduction through 2002.⁹⁷ Although California did not require divestiture of generation, utilities that wish to keep generation facilities must demonstrate to the California Public Utility Commission that doing so would be in the public interest

Montana allows utilities to recommend a method for assigning customers to a supplier who do not choose for themselves. *See* MONT. CODE ANN. § 69-8-203 (1999).

93. *See* Marla Dickerson, *A New Era in Electricity; Q & A Deregulation: What Happens Now?*, L.A. TIMES, Mar. 31, 1998, at D1. Legislation called for direct access by January 1998, but technical problems with the ISO and Power Exchange delayed the opening of the market. *See Final Opinion (Decision 97-12-131) Modifying Various Decisions Issued 12-30-97, Public Utilities Commission of the State of California, Dec. 30, 1997* (last modified June 8, 1999) <http://www.cpuc.ca.gov/electric_restructuring/decisions/d9712131/d9712131.htm>.

94. *See Energy Information Administration, Status of State Electric Utility Deregulation Activity, California* (last modified Oct. 1, 1999) <http://www.eia.doe.gov/cneaf/electricity/st_profiles/california/ca.html> [hereinafter EIA-California].

95. *See* CAL. PUB. UTIL. CODE § 367 (West 1999). The costs recoverable include power purchase contracts with qualifying facilities, capital and certain administrative costs for generation, including nuclear, and employee-related transition costs. *See id.*

96. Utilities are not permitted to recover “forward going costs” for fossil fuel plants, including maintenance and administration, with exceptions for circumstances in which market-based rates are not procurable in specific areas. *See id.* § 367(c).

97. *See id.* § 368(a). If the utility pays off its stranded costs before 2002, it may alter these rate levels. San Diego Gas & Electric paid off its costs two and a half years early, and responded by requesting an additional 10% rate reduction for its customers. *See* Nancy Rivera, *Utilities SDG&E Seeking 10% Rate Cut Thanks to Deregulation Payoff*, L.A. TIMES, Feb. 19, 1999, at C1.

and would not result in unfair market advantage.⁹⁸ Unlike most states, California implemented both an ISO and a Power Exchange. The Power Exchange functions as a competitive auction into which utilities bid and purchase wholesale power.⁹⁹

2. *Who Profits From Deregulation in California?* No one doubts that retail deregulation primarily benefits large industrial users. Although deregulation brought residential customers in California an immediate ten percent reduction on their electrical bill, consumer groups argue that this “discount” will ultimately be repaid by consumers because electricity rates will be increased to pay for the bonds that financed the initial discount.¹⁰⁰ Large industrial users, on the other hand, receive genuine discounts (up to twenty-five percent) on their purchases as a result of the competition for industrial customers.¹⁰¹ The disparity in rates has led to a disparity in the exercise of choice; only one percent of all electric customers switched providers in the first seven months of deregulation, but 24.9% of large industrial users switched.¹⁰² Independent energy providers complain that high stranded cost charges¹⁰³ make it impossible for them to compete in the market. Retail prices of wholesale electricity are now below wholesale costs, causing many providers to drop out of the market.¹⁰⁴ Perhaps the most chilling news for residential customers is that many companies and public agencies now form long-term strategic alliances with energy service providers because the market has become too complex for them to navigate efficiently on their own.¹⁰⁵ Unless residential customers are part of a municipality or

98. See CAL. PUB. UTIL. CODE § 377 (West 1999).

99. See Jim Rossi, *The Common Law “Duty to Serve” and Protection of Consumers in an Age of Competitive Retail Public Utility Restructuring*, 51 VAND. L. REV. 1233, 1283-84 (1998).

100. See Dickerson, *supra* note 93, at D1.

101. See *id.*

102. See Nancy Rivera, *Electricity Newcomers in Old-Power Struggle Energy: Amid Signs that Deregulation Is Catching on with Customers, Fledgling Providers Complain About Utilities’ “Monopoly Mentality,”* L.A. TIMES, Nov. 20, 1998, at C1.

103. Stranded costs now represent 25%-30% of the average utility bill. See Dickerson, *supra* note 93, at D1.

104. See *With Retail Prices Lower Than Wholesale, California ESPs Say They Cannot Compete*, Energy Services & Telecom Report, Nov. 19, 1998, available in 1998 WL 10029096. Of the 300 ESPs that originally registered to do business in California, less than 10 remain. See *id.*

105. See *id.*

other strategically allied group, it is difficult to see how they will be able to choose an energy supplier effectively.

C. Montana Leaves Retail Customers in the Cold

Montana passed deregulation legislation in 1997.¹⁰⁶ The statutes are broad and straightforward because they allow utilities a great deal of discretion in determining the path of restructuring. For example, rather than requiring utilities to serve as default energy providers, the Montana legislation requests utilities to suggest a method for determining the default supplier, or provider of last resort.¹⁰⁷ Utilities must maintain existing customer service requirements, as well as standards for safety and reliability, but the statute does not dictate what those standards should be.¹⁰⁸ Although utilities must functionally unbundle transmission, distribution and generation services, the Montana Public Utility Commission is prohibited from requiring or prohibiting divestiture of generation assets.¹⁰⁹

The results of this discretion have been mixed. Before deregulation, Montana citizens enjoyed access to low-cost hydropower.¹¹⁰ This may no longer be the case. Within months of deregulation, the Montana Power Company sold its generating facilities, five coal plants, and thirteen hydroelectric plants to an out-of-state company; thus Montana citizens are no longer guaranteed access to this low-cost electricity.¹¹¹ In addition, there is growing concern regarding the exploitation of water rights that accompanied the hydropower assets.¹¹² However, some cities in

106. See S.B. 390, 55th Leg., 1st Sess. (Mont. 1997).

107. See MONT. CODE ANN. § 69-8-203(2) (1999).

108. See *id.* § 69-8-401.

109. See *id.* § 69-8-204(1-2).

110. See Energy Information Administration, *State Electricity Profiles: Montana* (last modified Sept. 1999) <http://www.eia.doe.gov/cneaf/electricity/st_profiles/montana/mt.html>.

111. See Tom Kenworthy, *In Montana, A Volt Out of the Blue; After State Deregulated, Utility Decides It Wants to Generate Different Business*, WASH. POST, Mar. 4, 1998, at A2. Montana citizens may lose access to low-cost federal hydropower, because the federal Bonneville Power Administration says the co-op the Montana Legislature created to replace Montana Power is not a public utility and therefore may not buy from the 29 Columbia River Dams the agency operates. See Rob Eure, *Montana Co-op Fights to Buy Federal Power*, WALL ST. J., July 21, 1999, at NW1.

112. For example, the Avista corporation now holds water rights that could supersede the drinking water system for the city of Missoula. See Betsy Z. Russell, *Power Play Could Leave Some Dry; N. Idaho Vulnerable to Avista's Vast Water Rights*, SPOKESMAN-REVIEW, Feb. 28, 1999, at A1.

Montana are now purchasing power from alternate suppliers and achieving a limited reduction in rates.¹¹³

D. Imposing Residential Protection: The Oregon Plan

Newly passed legislation in Oregon, known as the Oregon plan, resembles bills offered in other states.¹¹⁴ The Oregon plan establishes a “public purpose charge” requiring three percent of total revenues from retail electrical sales to be used for renewable resources, conservation and market transformation, and low-income weatherization.¹¹⁵ Electric companies must functionally unbundle their generation, transmission, and distribution services,¹¹⁶ and the Oregon Public Utility Commission is authorized to provide incentives for divestiture of generation assets.¹¹⁷ Stranded costs may be recovered through a transition charge, although the Public Utility Commission may limit that recovery based on the public interest.¹¹⁸ Retail customers are permitted to aggregate their loads,¹¹⁹ and all retail customers, except for residential customers, must be given direct access to wholesale suppliers by the year 2001.¹²⁰

The key distinction of the Oregon plan is that it excludes retail residential customers from direct access. Instead of direct access, the plan requires that utilities give all residential and small commercial customers of IOUs a portfolio of rate options by the

113. Twenty-three cities have entered into contracts with Energy West Resources, and are expecting to save about 3% over the next 15 months. *See Montana Towns Saving in Deregulated Market*, ASSOCIATED PRESS NEWSWIRE, 11:27:00, Apr. 16, 1999, available in WL, Montana News.

114. *See* S.B. 1149, 70th Assembly, Reg. Sess. (Or. 1999); Jeff Mapes, *Senate Votes to Open Energy Market*, OREGONIAN, July 10, 1999, at B1; *see also* Fred Leeson, *Power's Free-Market Crawl*, OREGONIAN, Sept. 5, 1999, at B1 (describing growing frustration by industrial customers with Oregon's cautious approach to deregulation).

115. *See* S.B. 1149, 70th Assembly, Reg. Sess. § 3(1)-(2)(a) (Or. 1999). The funds gathered by the public purpose charge are divided as follows: 63% to conservation and market transformation, 19% for new renewable resources, and 13% for low-income weatherization. *See id.* § 3(b)(A)-(C).

116. *See id.* § 5.

117. *See id.* § 6(2).

118. *See id.* § 8(2). The transition charge must “reasonably balance the interests of retail electricity consumers and utility investors. The commission may determine that full or partial recovery of the costs of uneconomic utility investments . . . is in the public interest.” *Id.*

119. *See id.* § 9.

120. *See id.* § 2(1).

year 2001.¹²¹ In essence, the portfolio plan forces utilities to make generation choices on behalf of residential and small commercial customers. The utility would contract with energy service providers or power producers and then create different rate options for its customers. These rate options would have to include a market-based rate, a rate reflecting new renewable energy resources, and a cost-of-service rate.¹²² The Public Utility Commission would continue to regulate these rate options to ensure that they accurately reflect costs and risks.¹²³ Municipals and co-ops would have the option of offering direct or portfolio access or any other form of access that the governing board of the entity determines to be in its best interest.¹²⁴ However, if a municipal or co-op sought to serve retail customers of another electric company, it would have to provide reciprocal access to its customers by that utility.¹²⁵

The cost-of-service rate requirement is similar to the provision in most state plans that the utility remain the default provider, or provider of last resort, for customers who do not or cannot make a choice of suppliers.¹²⁶ States generally take one of two approaches in provider-of-last-resort circumstances. Under the first approach, the state requires the utility to take bids from other suppliers to provide for these customers. In the other, the utility can provide some or all of the power requirements from its own generation facilities.¹²⁷ Unless states mandate divestiture or open bids for generation, investor-owned utilities will supply their own wholesale power and will be regulated in essentially the same way they were before deregulation. Even if the utility does not supply the

121. *See id.* § 4.

122. *See id.* § 4(2). The cost-of-service rate represents the regulated rate allowed by the Oregon Public Utility Commission. For a discussion of public utility ratemaking, *see* Pond, *supra* note 13, at 5-13.

123. *See* S.B. 1149, 70th Assembly, Reg. Sess. § 4 (Or. 1999).

124. *See id.* § 24.

125. *See id.* §§ 11, 23.

126. *See* FOX-PENNER, *supra* note 13, at 277.

127. Pennsylvania requires utilities to purchase wholesale electricity at “prevailing market prices” for customers whose supplier does not provide contracted services or for customers who do not choose a supplier. *See* 66 PA. CONS. STAT. § 2807(e)(3) (1999). In Rhode Island, the utility must solicit bids in the unregulated market for the last resort power supply. *See* R.I. GEN. LAWS § 39-1-27.3(f) (1997). Maine’s Public Utility Commission regulates the standard-offer service rate, which is chosen by a competitive bidding procedure. However, utilities in Maine must divest all generation assets by March 2000. *See* Maine Public Utilities Commission, *Summary — Electrical Utility Restructuring in Maine* (last modified Oct. 5, 1999) <<http://www.state.me.us/mpuc/ersumm.htm>>.

wholesale power, the state public utility commission generally oversees the default rate offered by the utility to ensure that wholesale power is purchased at reasonable rates or market rates as required by the legislation.¹²⁸ Fluctuations in this rate will be determined by the cost of wholesale energy to the utility, which states cannot directly regulate.

Unlike other default provider provisions, however, the cost-of-service rate in the Oregon plan creates substantial protection for residential customers. Utilities can be required by the Public Utility Commission to purchase power from the Bonneville Power Administration, which markets low-cost hydropower generated at federal projects in the Columbia River Basin.¹²⁹ The Public Utility Commission also has the authority to order a utility to keep generation assets when necessary to provide customers access to low-cost power.¹³⁰ Putting these pieces together, the Public Utility Commission can essentially mandate a “just and reasonable” cost-of-service rate calculated with the presumption that utilities will use their low-cost wholesale power to supply the needs of residential customers. This provision ensures that utilities cannot attract industrial customers with low-cost power and leave less attractive residential customers with the remaining higher cost power. The Oregon Public Utility Commission has already rejected an application by a utility to sell hydroelectric facilities, because it determined that those assets should be maintained to provide low-cost power for residential customers.¹³¹

128. *See, e.g.*, 66 PA. CONS. STAT. § 2807(e)(3) (1999) (requiring the Public Utility Commission oversight to ensure that utilities buy power at “prevailing market prices”).

129. *See* S.B. 1149, 70th Assembly, Reg. Sess. § 19 (Or. 1999). The Bonneville Power Administration markets hydropower produced at federal projects in the Columbia River Basin. *See generally*, Michael C. Blumm, *The Northwest's Hydroelectric Heritage: Prologue to the Pacific Northwest Electric Power Planning and Conservation Act*, 58 WASH. L. REV. 175, 201 (1983). The Bonneville Power Administration has a statutory duty to give preference to public power needs when allocating its resources. Advocates of S.B. 1149 are unsure of the way the public power preference will disrupt their scheme for mandatory purchases from Bonneville Power Administration; thus a provision of the bill indicates that key provisions will take effect only if they do not compromise public access to Bonneville power. *See* S.B. 1149, 70th Assembly, Reg. Sess. § 18(1) (Or. 1999).

130. *See id.* § 6(2).

131. Portland General Electric petitioned the Oregon Public Utility Commission for permission to divest its generation facilities. *See* Portland General Electric Company, Order No. 913-117, 145 PUR 4th 113, 119 (Or. Pub. Util. Comm'n. 1993) (rejecting Customer Choice Plan). The Commission approved the sale of non-hydroelectric generation but denied Portland General

V. A MODEL FOR ALASKA

A. Should Alaska Deregulate?

Rural Alaskans are extremely concerned by deregulation proposals because they recognize that they are unlikely to be attractive customers in a competitive wholesale market.¹³² Some argue that deregulation has little to offer any retail customers in Alaska, because the high prices are a result of transmission costs rather than wholesale power costs.¹³³ Furthermore, because of the limited number of market players and limited transmission service, the Alaskan power market cannot afford mistakes and experimentation.¹³⁴ Others in the industry contend that Alaska will not be ready for deregulation until the transmission system is seriously improved; in particular, deregulation should await completion of the Northern and Southern Intertie.¹³⁵ However, a recent study of deregulation in Alaska concludes that deregulation, if implemented cautiously, could produce “measurable benefits” for Alaskans.¹³⁶ The study identifies heavy generation concentration, lack of public awareness, inadequate dispatch coordination, and significant stranded costs as the key areas of inefficiency that must be resolved to accommodate a move to competition.¹³⁷ An examination of all the various perspectives leads to one clear conclusion: Alaska cannot plunge into deregulation without serious consideration of the unique service problems it faces.

B. If It Deregulates, Alaska Should Look to Oregon for Guidance

At first glance, it may seem that any proposed legislation that would work for Oregon would be inapplicable to Alaska. Oregon

Electric permission to sell the hydroelectric facilities unless it could demonstrate that residential customers would not be hurt by the sale. *See id.* at Part XIII.A(4).

132. *See* CH2M Study, *supra* note 6, at 3.1; *see also* Tim Bradner, *Deregulation Divides Electric Utilities*, ALASKA J. COM., Mar. 1, 1999, at 10.

133. *See* Bradner, *supra* note 132 at 11. The wholesale power contributes only 25% of the costs of electricity in Alaska. *See id.*

134. *See id.* Chugach’s Beluga power plant generates close to half of the power for the state of Alaska. *See* Doug O’Harra, *Heart of the Dynamo: When the Beluga Power Plant Goes Down, Half of Alaska Loses Its Lights*, ANCHORAGE DAILY NEWS, Jan. 28, 1996, at G6. If Beluga experiences problems with even one of its generators, the entire Railbelt can end up in a blackout. *See id.*

135. *See* Interview with Kirk Gibson, Partner, Ater Wynne, LLP in Portland, Or. (Apr. 30, 1999) (on file with author).

136. CH2M Study, *supra* note 6, at 2.3.

137. *See id.*

has some of the lowest cost power in the United States, while Alaska has some of the highest. From a consumer's point of view, the Oregon Legislature should be focusing on how to encourage competition while maintaining access by retail consumers to certain low-cost power producers. Legislation implemented in California or Pennsylvania, which was directly motivated by a desire to decrease prices, to encourage competition, and to open access to new suppliers appears more directly applicable to Alaska.

However, unlike Alaska, most states with high cost power like California and Pennsylvania have access to well-developed networks for transmission and numerous power producers waiting in the wings to serve a deregulated market.¹³⁸ Alaska does not have transmission access to states in the lower forty-eight states, or even a comprehensive grid within the state. It also lacks a plethora of independent suppliers waiting to serve customers. Indeed, only two major utilities, Chugach and ML&P, currently have significant excess power to sell to customers.¹³⁹ Open markets simply cannot give Alaskan customers access to a variety of energy service providers. Consequently, the market for residential customers will lack genuine competition. Furthermore, unlike New England or the Midwest, Alaska does not have a dire need to develop resources to generate more power.¹⁴⁰ Instead, Alaska's current generation resources are expected to meet demand for the next twenty years.¹⁴¹ It will be difficult for any generator to challenge ML&P and Chugach because the limited number of consumers impedes development of economies of scale.¹⁴² Thus, like Oregon, Alaska must focus on developing competition within a relatively stable market of suppliers.

138. *See id.* at 2.1-2.2.

139. *See* Black & Veatch Study, *supra* note 58, at 5-2, 5-9. Golden Valley will have a capacity deficiency before the year 2016. *See id.* at 5-2, 5-7.

140. Analysts argue that New England and the Midwest are in serious need of new, efficient generation. *See* Charles W. Thurston, *Merchant Power: Promise or Reality*, 137 PUB. UTIL. FORT. 15, 17 (Jan. 1, 1999). Price spikes in the Midwest in the summer of 1998 were exacerbated by a thin peak reserve margin of generation, plants out of operation for regular maintenance, the alleged default of a small supplier, and bad weather. *See* Robert J. Michaels & Jerry Ellig, *Price Spike Redux: A Market Emerged, Remarkably Rational*, 137 PUB. UTIL. FORT. 40, 41-42 (Feb. 1, 1999).

141. *See* CH2M Study, *supra* note 6, at 1.2 to 1.3.

142. *See id.* at 2.5. The excess capacity and market share already held by Chugach leaves many people wondering if other independent power producers could compete effectively in the wholesale market. *See* Dan Joling, *Utility Redesign Gets Look*, ANCHORAGE DAILY NEWS, Jan. 19, 1999, at F1.

Although their motives are not the same, Alaska and Oregon both have important reasons for asking their current utilities to represent them in choosing wholesale suppliers and asking those utilities to continue offering a cost-of-service rate. First, both states have strong reasons to maintain aggregated networks of consumers. In Oregon, current access to low-cost power means that unless consumers are aggregated by the portfolio system, they are unlikely to command enough market power to achieve or exceed their current low prices. In Alaska, the small number of consumers mandates that they remain aggregated in order to have any amount of market share. The vast majority of customers in Alaska already belong to a cooperative or are served by a municipal utility that acts on their behalf to purchase or supply low-cost power. These utilities will lose market share if their customer base is disaggregated. Second, in Oregon, consumers want to be served by utilities that own low-cost generation assets; forcing the utility to offer a cost-of-service rate and to hold generation assets guarantees access to the low-cost power. In Alaska, small numbers leave residential customers particularly vulnerable to being left behind if utilities with excess capacity lower wholesale rates to attract large industrial customers and raise residential rates to accommodate the industrial rate shift.¹⁴³ A cost-of-service rate would enable the RCA to mandate that utilities with generation resources offer reasonable wholesale prices to residential customers.

C. How Alaska Can Learn From California and Montana

Alaska can learn some valuable lessons from the experiences of Montana and California in this area. California's residential customers have shown little interest in choosing new energy suppliers. Although residential and small commercial customers are seeing an immediate rate reduction, the price of that reduction may simply be passed back to the customers when financing bonds are repaid. Independent energy suppliers have made few inroads in the market because of high stranded costs compressed into a short time period. Alaska will have to offer residential customers something more than a short-term rate reduction, financed at their expense, to encourage them to learn about and operate in the wholesale electric energy market.

143. See Stephen Conn, *Utility "Cherry Picking" is Pits for Residential Users* *Compass*, ANCHORAGE DAILY NEWS, Jan. 22, 1999, at E12 (arguing that cherry picking will raise residential rates and that any pilot program should provide customers with accurate data of future electrical costs).

Montana's residents have learned that they cannot preserve regional benefits in a deregulated environment. If given the chance, investor-owned utilities will sell power wherever they can make the greatest profit. Although Alaska does not have to worry that its suppliers will send electricity outside the state, it must consider the impacts of default supplier and divestiture provisions within the state. In particular, Alaska must ask whether it wants to prevent the divestiture of generation assets if such divestiture would leave independent wholesalers free to choose to serve only large industrial users.

D. Adapting the Oregon Plan to Alaska

Alaska may not be ready for complete deregulation. However, deregulation does not need to be an "either-or" situation. Restructuring can take place on different levels, as seen in the different approaches of the California, Montana, and Oregon plans. The Alaska Legislature and the study group CH2M Hill have both recommended adopting a pilot plan for deregulation.¹⁴⁴ The following section outlines some suggestions for adapting the Oregon plan to Alaska.

1. *Portfolio Access.* As previously described, the market power of aggregated customers supports Alaska adopting a portfolio access plan with a cost-of-service option. The cost-of-service option would keep utilities with excess capacity, like Chugach and ML&P, from serving industrial customers at low rates and raising the rates for their residential customers. A divestiture provision like Oregon's would force utilities like Chugach to maintain their current generation facilities in order to provide residential customers access to lower-cost power. Alaska currently has no renewable resource generation.¹⁴⁵ A "green" portfolio option could be used to gauge demand and encourage the development of renewable resources, even if such options would not be immediately available to serve customers. The market-based rate would give the legislature insight into the actual costs of adopting competition on the residential level.

The portfolio plan can respond to customer apathy by ensuring that customers are not overwhelmed with information

144. See generally CH2M Study, *supra* note 6.

145. See *id.* at 1.10 tbl.1.6. Renewable resources include geothermal, biomass, wind, solar thermal, and photovoltaic. Golden Valley and Alaska Wind & Solar recently constructed a wind demonstration project consisting of a 10 kilowatt wind turbine placed on an existing tower. See *Healy Wind Study* (visited Oct. 4, 1999) <<http://www.gvea.com/Projects/wind.htm>>.

about the electric industry. Instead of being presented with a large number of providers or options, residential customers can simply look at a list of three or four options that their utility has chosen for them. By taking away some choice, customers may see less risk and thus may be more willing to experiment with market prices. The cost-of-service rate offers protection for customers who do not want to choose suppliers. However, the danger of this proposal is that if customers do not see a clear benefit in choosing a market option, their failure to choose may prevent the establishment of a competitive market.¹⁴⁶

The portfolio plan cannot prevent smaller providers, like Golden Valley, from raising residential rates if industrial customers in Golden Valley's service area are picked up by a utility with excess capacity.¹⁴⁷ This is a serious drawback to implementing any type of deregulation in Alaska. The RCA cannot artificially manipulate wholesale prices to protect small utilities since FERC has exclusive jurisdiction over the price of wholesale electricity.¹⁴⁸ Any additional restrictions on direct access, such as giving smaller utilities the choice to opt-out, seem to undermine the goals of deregulation. If every utility opts out of direct access except for ML&P and Chugach, these utilities will find themselves in much the same place they are today — with excess capacity and no access to willing buyers. One approach, suggested in the CH2M Study, would be to limit contract size and to avoid the current practice of serving customers on an all-requirements basis.¹⁴⁹ If combined with a mandatory power exchange similar to the one in California, this proposal could shift the balance between residential and industrial customers, allowing utilities to bid on market power to supply portfolio customers at the same prices as are offered to commercial and industrial customers.¹⁵⁰

2. *Allowing Small Utilities to Choose Deregulation.* The Oregon plan allows consumer-owned utilities to make their own decisions about direct access, but requires reciprocity if the utility

146. See CH2M Study, *supra* note 6, at 2.7.

147. See Bradner, *supra* note 132. Remote villages are probably safe from cherry picking, but coastal villages in the Railbelt with few industrial customers, maybe a fish processing plant, and a hospital, are particularly vulnerable. See *id.*

148. See *supra* note 13.

149. See CH2M Study, *supra* note 6, at 2.5-2.6.

150. Once again, however, the cost of implementing a power exchange in Alaska could outweigh the benefits, particularly in the short term if the industry is already struggling with stranded costs and the costs of establishing an ISO. See *id.* at 2.9.

seeks to serve customers of another utility.¹⁵¹ If instituted, this provision would grant discretion over deregulation to the majority of utilities in Alaska.¹⁵² Alaska's current regulatory scheme treats consumer and investor-owned utilities alike, basing regulation on revenues rather than ownership.¹⁵³ Size, or revenue, appears to be a better category for distinguishing which utilities should have control over the decision to deregulate, because market power is such a concern for Alaskans. To accommodate this concern, Alaska should keep its current statutory provisions, and order portfolio access for those utilities that the RCA currently regulates. Small utilities, whether cooperative or investor-owned, would be responsible for deciding whether or not to offer their customers direct access. For the numerous tiny utilities with purely local transmission and distribution, deregulation holds little promise in any case, because it would be cost prohibitive to run transmission lines to villages simply to allow Railbelt utilities access to a small number of residential customers.¹⁵⁴ Until there are significant improvements in current facilities and technology, competition is unlikely to penetrate rural Alaska.

3. *Limiting Stranded Costs.* Any implementation of deregulation in Alaska will have to proceed cautiously. The threats of market power concentration and higher costs for residential customers present significant obstacles. California's aggressive approach to stranded costs has limited market penetration by energy service providers.¹⁵⁵ In California, energy service providers may temporarily leave the market and return when stranded costs are paid off and the climate is healthier for their survival. This will

151. See S.B. 1149 70th Assembly, Reg. Sess. § 24 (Or. 1999).

152. See *supra* note 67. Proposed legislation essentially adopts this scheme, but in a backward manner. See H.B. 287, 20th Leg., 1st Spec. Sess. (Alaska 1997). This bill does not require direct access. Instead, it allows any utility that grants direct access to its transmission and distribution facilities to request the RCA to order that it be able to access another utility's facilities. See *id.* The RCA would not issue such orders unless the second utility had annual sales of at least 300 million kilowatt hours. See *id.*

153. See *supra* notes 75-76 and accompanying text.

154. For this reason, the CH2M Study concluded "[t]here is no restructuring model in existence today that would work in rural Alaska among the villages and cities that are not interconnected to the Railbelt System." CH2M Study, *supra* note 6, at 2.1. Instead, the study proposes improving local generating systems and encouraging "technological innovations that could complement or even compete with the diesel-fired generation systems currently dominating rural electrical systems." *Id.*

155. See *supra* note 104.

not be the case in Alaska. If a producer in Alaska cannot access the market, it will go out of business. Alaska should examine alternate methods of financing stranded costs, including public bonds. It should also discuss adopting an extended time period for stranded cost recovery to ease the transition into competition and save small players from bankruptcy.

4. *Postponing the Transition to Competition.* Alaska should consider implementing competition in stages to limit cost and market impact.¹⁵⁶ For example, over the next five to ten years, Alaska might implement and pay for an ISO and power exchange. This time period would allow the ISO to become a cost benefit before further deregulation costs are imposed. A multiple year transition time would ensure that the Northern and Southern Intertie construction could be completed before competition was imposed, and would give the RCA time to implement technological improvements to rural systems. An extended transition period would also allow utilities that are currently in long-term contracts to renegotiate those contracts to correspond to a deregulated market.¹⁵⁷ These proactive contract negotiations could substantially mitigate stranded costs.

Alaska loses little by postponing deregulation, as long as it establishes a plan and a model for future legislation. If it does not adopt a concrete proposal and time-line for deregulation, power producers will be unwilling to negotiate short-term contracts based on restructuring. Postponing the costs of deregulation also postpones the benefits. However, these losses seem minimal when compared to the potential for premature action to injure the developing market.

156. The CH2M Study calls this “controlled evolution.” CH2M Study, *supra* note 6, at 2.2.

The time sacrificed by taking this longer approach is applied to developing not just structural mechanisms, but a body of rules that guide markets toward desired economics and social outcomes. Regulation is ultimately supplanted under this scenario by the constant competitive pressure applied by a diverse range of market entrants with the freedom and incentives to respond to market opportunities.

Id. at 2.2-2.3. This approach is contrasted with what the authors call “kilowatt commoditization,” in which structures are relied upon to regulate the market, regulators have little oversight, and success or failure turns on underlying market conditions. *See id.* at 2.2. This approach is most similar to that adopted in Montana. *See supra* notes 106-113 and accompanying text.

157. Long-term contracts would have to be renegotiated to implement either a power pool or an ISO. *See Black & Veatch Study, supra* note 58, at 6-6.

5. *Universal System Benefit Charge.* Alaska is already struggling with ways to continue its subsidies for low-income residents.¹⁵⁸ Most states that have implemented deregulation place a universal system benefits charge on utilities based on annual revenues.¹⁵⁹ Implementing a charge like this would place an additional burden on rates and could even outweigh the limited benefits of competition.¹⁶⁰ Legislators have expressed immediate opposition to current proposals to establish a universal service fund created from a direct surcharge on electricity sales.¹⁶¹ Without some sort of subsidy program, many small village utilities could go bankrupt.¹⁶² More so in Alaska than in any other state, subsidies are not a question for the electric industry to solve on its own. If Alaska wants to protect low-income residents and eliminate a portion of the price differential between remote villages and the Railbelt, it must implement some sort of broad-based universal charge, either on utilities or on customers, and work to develop technological improvements in village generation, transmission, and distribution.¹⁶³

VI. CONCLUSION

Deregulation provides Alaska with the opportunity to evaluate its current regulatory scheme. Inefficiencies in the current scheme include inadequate transmission, a lack of coordination among rural villages, and a concentration of generation and surplus power existing alongside high prices. Legislators in Alaska must approach deregulation cautiously, and preserve Alaska's tradition of supplying reasonably priced power to all residents. Before legislators make any move towards offering direct access to wholesale power, they should make sure adequate safeguards exist to protect retail customers from market power problems. The benefits to industrial customers should not come at the expense of

158. See *supra* notes 83-86.

159. See *supra* note 90.

160. See CH2M Study, *supra* note 6, at 7.8.

161. See Joling, *supra* note 57, at D1.

162. See *id.*

163. The CH2M Study recommends that the legislature “[c]ontinue and expand efforts to improve rural system efficiencies through aggregation of administrative, fuel-purchasing, operations, logistical and other appropriate functions among geographically separate but proximate villages.” CH2M Study, *supra* note 6, at 2.12.

residential customers, particularly those in rural areas already bearing costs many times higher than urban residents.

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